PETROLEUM SOCIETY
CANADIAN INSTITUTE OF MINING, METALLURGY & PETROLEUM

PAPER 2004-017

CANADIAN INTERNATIONAL
PETROLEUM CONFERENCE

Asian-Pacific Markets – A New Strategy for Alberta Oil

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This paper is to be presented at the Petroleum Society's 5th Canadian International Petroleum Conference (55th Annual Technical Meeting), Calgary, Alberta, Canada, June 8 – 10, 2004. Discussion of this paper is invited and may be presented at the meeting if filed in writing with the technical program chairman prior to the conclusion of the meeting. This paper and any discussion filed will be considered for publication in Petroleum Society journals. Publication rights are reserved. This is a pre-print and subject to correction.

Abstract

With new oilsands projects and expansions of existing projects coming onstream, it is anticipated that production of heavy crude and bitumen will reach more than two million barrels per day by 2012, and over five million barrels per day by 2030 (on a synthetic crude oil basis). It is assumed that most of this anticipated production can be marketed in the United States; however, the U.S. currently only accepts limited volumes of synthetic crude oil (SCO), as it must be blended with other crude to meet refinery specifications. This combination of limited U.S. refinery capacity and current SCO quality means there is risk that much of this new production either cannot be marketed, or that market price will be reduced because of oversupply, unless new markets can be found.

An obvious new market for Canadian heavy oil and bitumen is the Asian-Pacific region, due both to increasing demand for petroleum products and proximity. The Alberta Energy Research Institute, in partnership with industry from Asia and Canada, is investigating both short and long-term exports of Alberta crude and value-added products to Asia. This paper provides an update on this study, which will identify the technology gaps that should be addressed to match Alberta products to Asian refineries.

Introduction

In recent years, markets have overtaken supply as the main concern for Alberta's heavy oil and bitumen producers and the Alberta government. Although the province has proven reserves second only to Saudi Arabia, the higher production costs and lower quality of our heavier feedstocks have made it more difficult to export the rising volumes of bitumen and synthetic crude production to existing markets in the United States.

Although Canada is favorably positioned both geographically and politically to continue as a supplier to U.S. markets, economic reality shows that the refineries in the U.S. Midwest (PADD II), which is the single largest traditional market for Canadian oil producers, cannot absorb further imports of heavy feedstock without the addition of significant residual upgrading capacity. These refineries are already facing significant capital expenditures for process units to meet Clean Fuels Initiatives (low-sulphur gasoline phased in over a three-year period from January 2004, and low-sulphur on-road diesel in 2006 and off-road diesel in 2007) and other regulatory requirements (for example, the replacement of MBTE); thus, the likelihood of the addition of further conversion capacity is low[(1)]. In addition, Alberta producers are facing increasing competition in the PADD II market from the U.S. Gulf Coast, which refines heavy crude from Mexico and Venezuela.

Although there is some room for further imports to refineries in PADD IV, other potential U.S. markets, such as California and the U.S. Gulf Coast, cannot be accessed by Alberta producers without the addition of new pipeline capacity, or the reversal of existing pipelines. The other option is to export outside of North America, which will also require new infrastructure. An obvious new market for Canadian heavy oil and bitumen is the Asian-Pacific region, due both to a rapidly increasing demand for petroleum products and proximity, and the potential of reaching the California market with the same pipeline.

The success of any initiative to move Canadian crude oil to Asian-Pacific markets will depend on three criteria: a sustainable supply of crude from Alberta, a pipeline to transport the crude to a deepwater port on the West Coast, and a guaranteed market at the other end. This paper will examine all three of these issues, and discuss the feasibility of marketing Alberta heavy oil and bitumen to Asia.

Alberta Bitumen Supply and Constraints

Alberta's oil sands contain an estimated crude bitumen-in-place of close to 2.5 trillion barrels (397 billion m^3). As reserves of conventional oil decline in Alberta, production from the oil sands has gradually increased to the point where it has overtaken non-conventional sources (see Figure 1). For example, Alberta's total crude oil and equivalent production (including condensate) in 2002 was 1.5 million barrels per day, of which 48 percent was non-upgraded bitumen (299 Mb/d) and synthetic crude oil (435 Mb/d)[(1)]. Over one third of the bitumen production was derived from in situ projects, with the remainder coming from mining operations.

Should all planned new oilsands projects and expansions of existing projects come onstream, it is anticipated that bitumen production will reach approximately two million barrels per day by 2012, and over five million barrels per day by 2030 (on a synthetic crude basis)[(2)]. However, the industry is facing severe constraints that may affect both potential crude oil production and existing market share.

Natural Gas

In situ oil sands projects are heavily dependent on natural gas used in burners or cogeneration plants to generate steam to separate bitumen from sand, and to produce electricity. Natural gas is also the feedstock of choice to produce hydrogen for upgrading. Competition from other markets, as well as dwindling reserves, have already caused increased natural gas prices, threatening the economic advantage of Alberta oil exports. Although new sources of natural gas, such as the Mackenzie Delta and coalbed methane, are projected to come onstream in the coming 5 – 10 years, it is projected that the entire supply of gas coming out of the North could be consumed by oil sands projects alone[(1)]. As a result, bitumen producers are seeking alternative fuels to provide power and hydrogen. The Alberta Energy Research Strategy identifies the gasification of coal, petroleum coke, and bitumen bottoms as one of the more promising technologies to fill the need for natural gas replacement[(3)], and Nexen and OPTI will be implementing an integrated gasification process at their Long Lake SAGD-upgrading project.

Water

Water is used to generate steam for in situ projects, and in oil sand extraction, upgraders and refineries. The net permanent loss for SAGD and other in situ projects is expected to be 0.2 to 0.3 barrels of water for every barrel of oil recovered, and approximately ten times of that amount for mining projects[(2)]. There are also issues related to the discharge of excess water and tailings water, which can be saline or contaminated with hydrocarbons. The Alberta government, in its "Water for Life Strategy" has identified water conservation as a key area of concern, and this must be addressed in all future projects[(4)].

Environmental Impact

In addition to the area of water management, there are growing regulatory pressures to reduce the environmental impact of oil sands projects, chiefly in the areas of land reclamation and emissions. Still uncertain are the effects of compliance with the Kyoto accord, which has the potential to increase operating costs of oil sands projects up to $1.50 per barrel[(1)]. Increases in capital and operating expenditures to address these issues will have an overall effect on the supply cost of Alberta bitumen.

Capital and Operating Costs

The most important variable in determining bitumen supply cost is the capital cost of developing a project. In recent years, cost overruns on major projects such as Suncor's Millenium project, the Albion Oil Sands project, and Syncrude's Stage 3 expansion have caused other operators to rethink their expansion strategies.

Diluent

Unprocessed bitumen is currently shipped to market by dilution with gas field condensate, typically in the 24 to 32% by blend volume range. Diluent requirements are expected to triple over the next 10 years as the industry expands; however, a shortfall has already been predicted for as early as 2005. Some producers are already blending their bitumen with synthetic crude oil ("synbit"), although this requires a higher (approximately 50%) blend volume to meet pipeline specifications. Alternate methods of viscosity reduction, such as field upgrading or a new central upgrader, will be needed in future to reduce or eliminate diluent demand.

Light-Heavy Differential

Although some of Alberta's in situ produced bitumen and heavy oil is upgraded in Husky's Lloydminster upgrader, most of the remainder is shipped to refineries in the United States, primarily to PADD II. However, unprocessed bitumen has historically brought a lower price to producers (the light-heavy differential). A large differential generally results in the shutdown of uneconomic projects in Alberta, although it makes Canadian crude more attractive to U.S. refiners

Purvin & Gertz have suggested that Alberta producers could maintain their market share in the U.S. Midwest by paying for new refining facilities via accepting lower netbacks[(5)]. However, more favorable economic returns to both producers and the Alberta government could be achieved through market diversity; either by accessing new markets, or by selling value-added products produced by further upgrading and refining in

Alberta. The latter option has also been identified by AERI as a key goal in the Alberta Energy Research Strategy [3].

Bitumen Quality

Upgrading affects the quality of the bitumen exported from Alberta, as well as the volume and price (see Figure 2). There are a limited number of U.S refineries that can handle unprocessed high acidity, heavy Alberta crude, due to high percentages of residue and sulphur. These are primarily located in PADD II. Conventional upgrading methods such as coking, which are based on severe thermal conditions, produce a highly aromatic synthetic crude, with poor quality distillates, although the sulphur content is low. About half of synthetic crude oil is used in Canada, with the remainder shipped to PADDs II and IV. Refineries have blended upgraded Alberta oil with other crude in the past; however, as production increases, this ability will be lost, and markets will tighten.

Technical solutions are feasible for many of the constraints facing heavy oil and bitumen producers in Alberta, and it is likely that crude production will continue to grow as anticipated. However, the existing market issue is one that can only be solved technically with a major investment by U.S. refiners in new conversion capacity. Even then, it is doubtful that there will be enough refinery space in the U.S. to handle the volumes that are projected from Alberta in the coming 20-30 years. One obvious solution is to seek new markets. The rapid economic growth in the Asian-Pacific region, which has a major dependence on Middle East oil, makes countries such as China, Japan, Taiwan and Korea attractive potential markets for Alberta crude

Export Pipeline Capacity

One of the key issues in the success of exporting crude oil overseas is the availability of pipeline capacity. Suncor currently markets a limited amount of Alberta crude to Japan via Terasen's Trans Mountain Pipeline to Vancouver; however, dedicated shipments to Asian markets cannot be guaranteed under current capacity[6]. Both Enbridge Inc. and Terasen Inc.have announced that they are actively seeking long-term contracts in Asia to support rival pipeline links to the Pacific. Terasen is considering a staged expansion of the existing Trans Mountain line, which would allow for an extra five cargoes of heavy crude per month to be shipped to Vancouver. In addition, it is examining the possibility of constructing a new pipeline from Hardisty to Bakersfield, which could be in service as soon as 2008, and could also give access to Asian markets (see Figure 3) [7]. Enbridge's $2.5 billion Gateway project is more ambitious; at capacity, this line would pump up to 400,000 barrels per day of crude from Edmonton to a deep-water port in Prince Rupert [8]. The oil could then be shipped to either Asia or California markets. One of the more attractive features of the west coast options is the relatively short shipping distance to Asian markets; Figure 4 shows that Prince Rupert is approximately equidistant to Japan as the Persian Gulf, and 100% closer than Venezuela.

If and when these lines are built depends on several factors, one of which is the securing of dedicated customers in Asia. Although it appears unlikely that refiners will substantially increase their heavy oil conversion facilities, should this occur, the higher netbacks estimated for the western pipelines will no longer be as competitive.

Potential for Asian-Pacific Markets

The largest markets for crude oil in the Asian-Pacific region are Japan, Korea, and China. All of these countries are currently heavily dependent on imports from the Middle East to meet their energy requirements, chiefly from Saudi Arabia. Despite the increasing energy demand and dependence on external sources of energy, this region has become increasingly vulnerable to a reduction in supply, due to the lack of a fully-developed emergency response system, such as an oil stockpile. Other risk factors affecting Asian petroleum imports include territorial disputes, political turmoil, and increasing unemployment in the Middle East, as well as increasing demand for tankers to transport crude oil and global volatility of oil prices. Canada's political stability and competitive oil prices are of increasing interest to Asian countries interested in a secure long-term energy supply.

Japan

In 2002, Japan imported a total of 4.0 million b/d of crude oil, of which 86.8% of that was from the Middle East. The remaining imports were from Africa (3.8%), other Asian sources, primarily China (7.5%), and other sources such as Russia (1.9%)[9]. Although major efforts have been made in Japan to focus more on alternate energy sources such as natural gas, coal, and nuclear, crude imports have decreased only slightly since a peak in 1995, and the Middle East remains a key supplier. For example, in February 2004, Middle East sources supplied 92.6% of Japanese crude oil imports[10].

As can be seen in Table 1, Japan has 33 refineries, with a charge capacity of 4.7 million b/d. Due to the increasing use of natural gas and coal to supply power, these refineries are not fully utilized (81.4% utilization ratio in 2002), and a projected drop in fuel oil demand by approximately 1.4% per year to 2007 is expected to reduce the utilization ratio even further. Further reductions could take place if initiatives to introduce higher levels of ethanol in gasoline, and biodiesel, are successful.

The majority of Japanese crude oil imports can be classified as medium or light sour. However, close to 95% of Japan's distillation capacity has been equipped with desulphurization units to meet increasingly stringent fuel sulphur specifications. The sulphur content of gasoline must drop from 100 ppm to 50 ppm at the end of 2004, and must be sulphur free (below 10 ppm) by 2008. Diesel sulphur content will be reduced to 50 ppm by the end of 2004 from the current value of 500 ppm, and must be sulphur free after 2007. Japanese refineries will voluntarily supply sulphur free gasoline and diesel in limited areas by 2005[9].

Japan has already indicated an interest in pursuing a long-term relationship with Alberta through a 75% ownership of the Hangingstone SAGD project by Japan Canada Oil Sands. With an excess in refinery capacity designed to handle medium sour crude, and extensive desulphurization capability, Japan could easily meet its import requirements with Canadian "dilbit" or "synbit" blends. However, Figure 5 illustrates a projected decline in annual growth of oil demand, which will primarily be due to Japanese government efforts to reduce its dependence on petroleum as an energy source. Although gasoline demand is expected to increase, a drop in diesel as well as fuel oil demand will be the primary reason for the decline. The naphthenic nature of Alberta bitumen will therefore make it a somewhat less desirable feedstock for Japanese refineries should these projections hold accurate.

Korea

Korea imported 2.1 million b/d of crude oil in 2002, with 74.5% of the oil deriving from Middle East sources. The two other largest suppliers were Indonesia (5.5%) and the Congo (2.7%), with the remainder coming from a variety of suppliers including Canada (0.1%)(9). Korea has a total of 6 refineries, with a charge capacity of 2.5 million b/d (Table 1); these refineries run at a near 100% utilization rate, and any excess products are exported.

Oil demand in Korea is expected to hold steady (Figure 5), with forecasted increases for all refinery products except for kerosene based on the assumption of strong industry and transportation sectors. Fuel sulphur specifications are not as stringent as those in Japan; gasoline sulphur content will drop to 50 ppm from the current level of 130 ppm by 2006, and that of diesel to 30 ppm from 430 ppm. The existing import relationship with Canada, and the projected increase in demand for diesel and boiler feed, should make Alberta bitumen an attractive option for Korean refineries.

China

Unlike Japan and Korea, China has a strong domestic petroleum industry, dominated by two major companies: China National Petroleum Corporation (CNPC), which controls about two thirds of domestic crude oil production capacity, and China National Petrochemical Corporation (SINOPEC), which controls more than half of the refining capacity. The majority of CNPC's assets are under the umbrella of PetroChina, which is a public corporation. Offshore exploration and production is the mandate of the China National Offshore Oil Corporation (CNOOC); however, this company only accounts for about 10% of domestic production.

Prior to 1993, China was a net exporter of crude oil (see Figure 6). Since then, China's explosive economic growth has fuelled a dependence on foreign oil, which has grown by approximately 5% per year. In 2004, imports are projected to make up 41% of China's total oil requirements(11). This trend is expected to continue through 2020 (Figure 5), with incremental oil demand growing by 5.7 million b/d between 2000 and 2020.

China is slightly less vulnerable to fluctuations in Middle East oil exports than are most of the other Asian-Pacific countries. In 2002, China imported a total of 1.4 million b/d of crude oil, of which only 49.5% was shipped from the Middle East(9). However, by the end of 2003, imports had risen to an average of 1.9 million b/d, with 56% from Middle Eastern producers(11). Other major exporters of crude oil to China are Angola, Sudan, Vietnam, Indonesia, Malaysia, and Russia; however, oil has been imported from as far away as the North Sea, to ensure a diversity of supply. China is also implementing an emergency response system, by dedicating six sites, most of them near major refining and transportation centres, with a storage capacity of 350 million barrels to provide 30 days of import cover by 2005, and 50 days of import cover in 2010(11).

China has a total of 95 major refineries, with a total of 4.5 million b/d charge capacity (Table 1). However, there are a number of smaller local government-registered refineries, which increase the total to 131, and the charge capacity to 5.2 million b/d). The total crude oil processed in China in 2003 (actual) was 4.6 million b/d, and products were imported to meet the total consumption of 5 million b/d, which is increasing steadily to meet the demands of economic growth(11). Most of the processing capacity in Chinese refineries is concentrated on fluid catalytic cracking units, as the Chinese domestic crudes are highly paraffinic, and the majority of imports have historically been light crude. However, this has resulted in a higher percentage of gasoline being produced, while the majority of domestic demand is for diesel to fuel the transportation sector for agriculture and manufacturing. Projected diesel demand will remain high, with a ratio of diesel to gasoline demand of 2.4, through 2020(9). Demand for gas oil and fuel oil has also been increasing steadily, averaging about 25% in 2003(11).

China faces several key challenges in trying to fit its refining capacity to supply and market demand. Most Chinese refineries have difficulty in meeting product specifications; gasoline generally has a high olefin content and low octane number, and diesel fractions have a high sulphur content and poor stability. Only seven Chinese refineries can accept high sulphur crude, which has led to a lack of stringent standards and allowable sulphur contents of 800 ppm for gasoline and 2,000 ppm for diesel (500 ppm in urban areas). In addition, Table 1 shows that, in general, Chinese refineries are poorly equipped to handle large volumes of heavy crude; this will be a concern as local production and imports grow heavier.

Due to its domestic production, China's imports of crude oil are less than those of Japan and Korea. However, if its economy continues to grow as projected, China will eventually outstrip them as a major oil importer in the Asian-Pacific region (Figure 5). In terms of sustained market growth, China is an attractive export market for Alberta producers. However, China's inadequate heavy crude refining capability and lack of desulphurization units make it a poor receptor for "dilbit" or "synbit" blends. On the other hand, as production of synthetic crude oil outstrips the ability of Alberta refineries to absorb it, SCO would be a desirable feedstock for Chinese refineries, due to its higher diesel yield and low sulphur. Figure 7 illustrates the major attractions of Alberta synthetic crude for existing Chinese refineries.

Discussion

The three major oil importers in the Asian-Pacific region have all been shown to have market potential for exports of Canadian crude, through proximity and the ability to process Alberta bitumen and heavy oil. Japan, which is by far imports the largest volumes of crude oil, has the refinery capacity and desulphurization capability to handle exports of "dilbit" or "synbit" blends. Japan is also developing production capacity in Alberta, through a 75% ownership of the Hangingstone SAGD project. However, the Japanese government is taking action to reduce the country's dependence on foreign oil, which will mean a gradual slowdown in demand over the next decade. Korea, with the second largest level of current crude imports, has an existing marketing relationship with Canada, and a forecasted strong demand for petroleum products. Both of these factors make Korea an attractive export market for Alberta bitumen.

China has the lowest dependence on crude oil imports, but this is forecasted to change should its economy continue to grow. Although China's existing refineries are poorly equipped to process "dilbit" or "synbit" blends, imports of Alberta synthetic crude oil would be an excellent blending stock with Chinese domestic crude, and would help China to meet its rapidly escalating diesel demand. Although most of Alberta's synthetic crude production is now processed locally, by the time that pipeline infrastructure is in place to ship the SCO, Alberta's producers should be able to meet the demand. A financial incentive for this option is that, instead of shipping a low-value product with a high differential, Alberta producers could command a higher price for their crude, and the added value of upgrading would be retained in Canada.

Figure 8 shows the vision for Canada's oil sands to 2030, and it shows that, in addition to an increased production of bitumen and synthetic crude, there will also be value-added products such as "green" fuels and petrochemicals produced in Alberta. Although there is a limited market in the Asian-Pacific region for these products at this point in time (China is currently largest overseas importer of Alberta ethylene), there is also the potential to retain even more of the added value of upgrading and refining in Canada through the expansion of this market.

Exporting Canadian oil to Asian-Pacific markets does have its drawbacks. Unless long-term contracts are obtained, it will be difficult to recoup the infrastructure costs required to transport the crude to the west coast of British Columbia. Government policy and regulatory issues will need to be examined at both ends of the import-export relationship. Also, current financial predictions are based on strong and sustained growth in the Asian-Pacific region, which is highly dependent on sustaining the Chinese economy at its current levels. For example, exports to China accounted for 73% of Japan's export growth in the first 8 months of 2003, and a similar pattern was observable for exports by Australia, Malaysia, and Singapore[(12)]. China's rapid economic growth is thus a key factor in maintaining a vibrant Asian economy; however, this close integration may also leave the rest of Asia more exposed if the Chinese economy slows.

Conclusions

Market prices for Canadian crude exports have historically been set by the PADD II market. Unless new conversion capability is added in the U.S. Midwest, a scenario that seems unlikely given the focus on sulphur reduction and clean fuels in the United States, prices for Alberta's heavy oil and bitumen will drop as the market saturates, with the eventual risk of curtailing the projected expansions to oil sands production. An obvious solution to this problem is to seek new markets for our oil; an idea which is high in the sights of producers, pipeline companies, and the Alberta government.

The three largest crude oil importers in the Asian-Pacific region have been examined, and all have been found to be attractive prospects as export markets for Canadian crude. China, which currently imports the smallest amount of crude oil, has the most promise in the long-term, with the potential of exporting a value-added product out of Alberta. However, the success of such an export venture will require the cooperation of governments at either end of the exchange, to ensure that regulatory and policy issues do not hamper the development of infrastructure and trade. In addition, long term contracts will need to be secured in both Alberta and Asia, to ensure that the necessary pipelines can be built and as a hedge against risk should the Chinese economy slow.

Acknowledgements

The authors would like to acknowledge PetroChina for co-funding the feasibility study on utilization of Alberta crude oil in Chinese refineries with the Alberta Energy Research Institute.

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TABLES

Table 1.Refining capacities in Japan, Korea, and China for 2004 (x1000 b/d) [9]

	Japan	Korea	China
Number of Refineries	33	6	95
Charge Capacity (x 1000 b/Cd)			
Crude	4,703	2,544	4,528
Vacuum Distillation	1,663	315	40
Coking	93	19	306
Thermal Operations	0	0	0
Catalytic Cracking	876	179	892
Catalytic Reforming	730	228	157
Catalytic Hydocracking	173	120	122
Catalytic Hydrotreating	4,336	1,003	355
Production Capacity (x 1000b/Cd)			
Alkylation	48	5	27
Pol./Dim.	7	0	0
Aromatics	251	110	0
Isomerization	21	0	0
Lubes	42	15	49
Oxygenates	4	9	1
Hydrogen (MMcfd)	1	1	0
Coke (Tonnes/d)	2	1	5
Sulphur (Tonnes/d)	9	3	0
Asphalt	119	24	0
Secondary Units/Topper Ratio (%)			
Vacuum Distillation	35.4	12.4	0.9
Coking	2.0	0.7	6.8
Thermal Operations	0.0	0.0	0.0
Catalytic Cracking	18.6	7.0	19.7
Catalytic Reforming	15.5	9.0	3.5
Catalytic Hydrocracking	3.7	4.7	2.7
Catalytic Hydrotreating	92.2	39.4	7.8

FIGURES

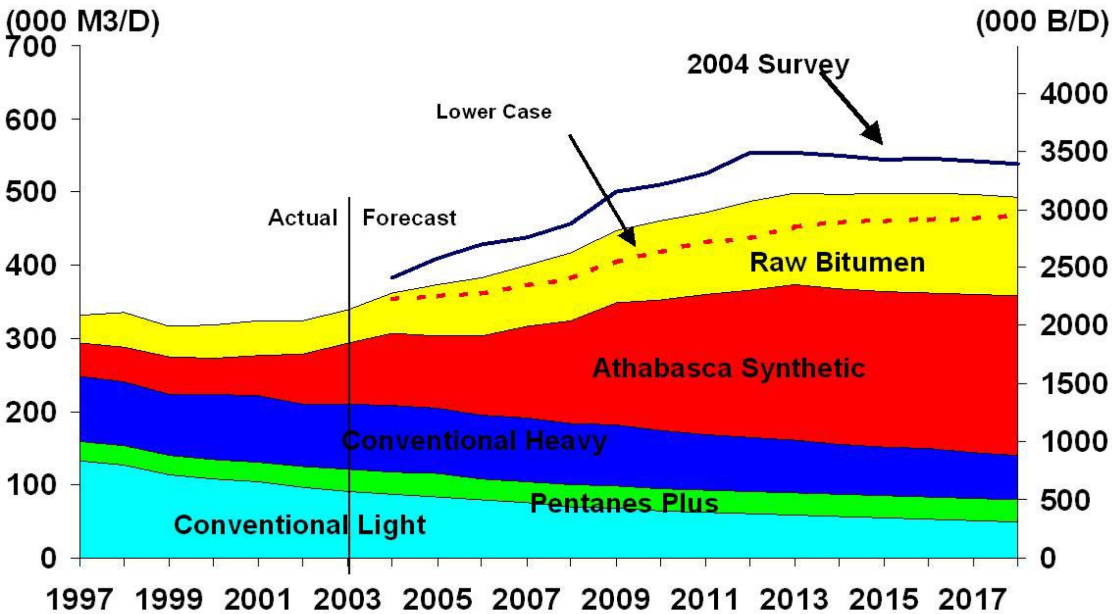

Figure 1. Western Canada sedimentary basin crude oil production potential.

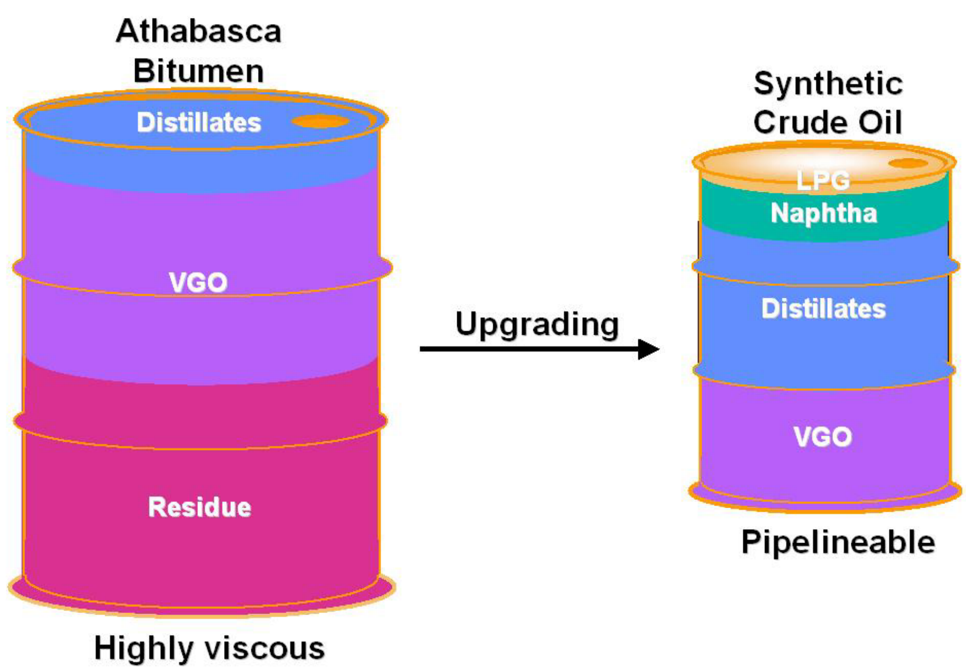

Figure 2. The effect of upgrading to synthetic crude oil for Athabasca bitumen.

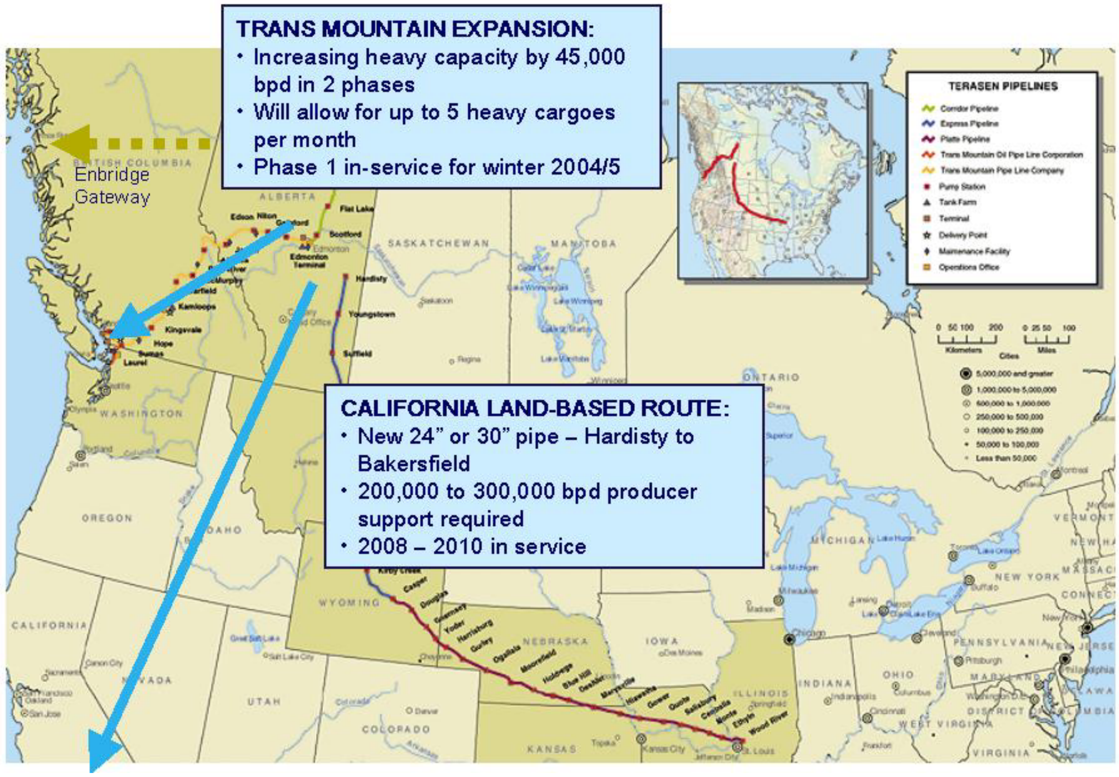

Figure 3. Expansion plans for Terasen's pipelines[7].

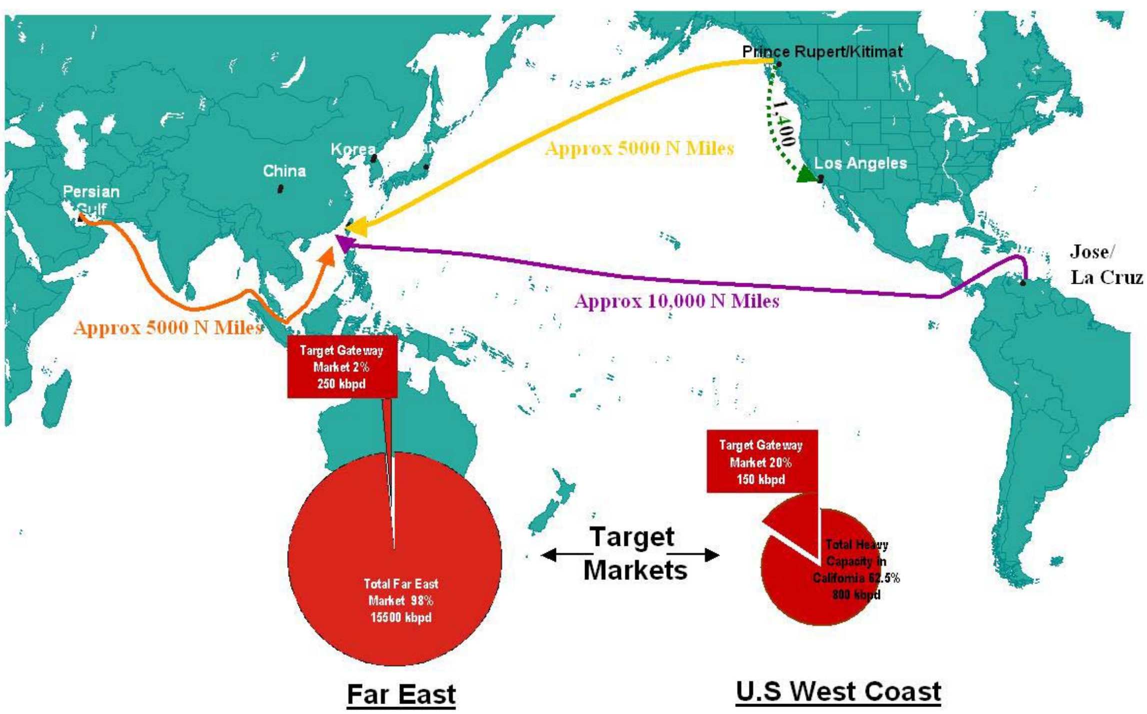

Figure 4. Target markets for Enbridge's Gateway project.

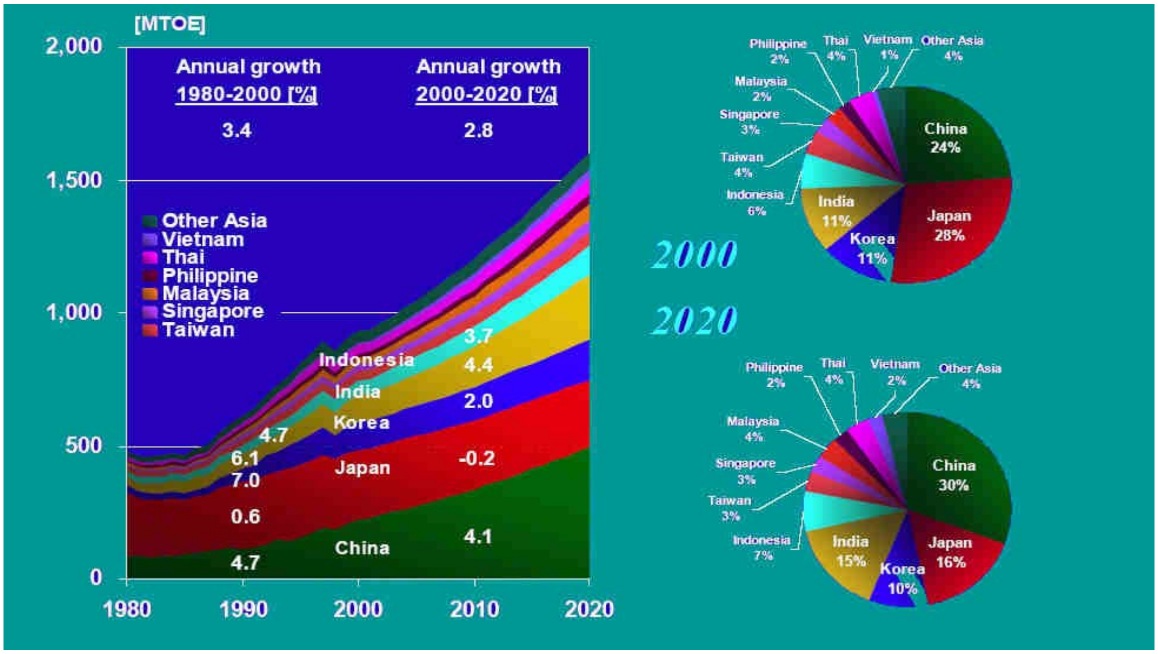

Figure 5. Regional overview of Asian oil demand[9].

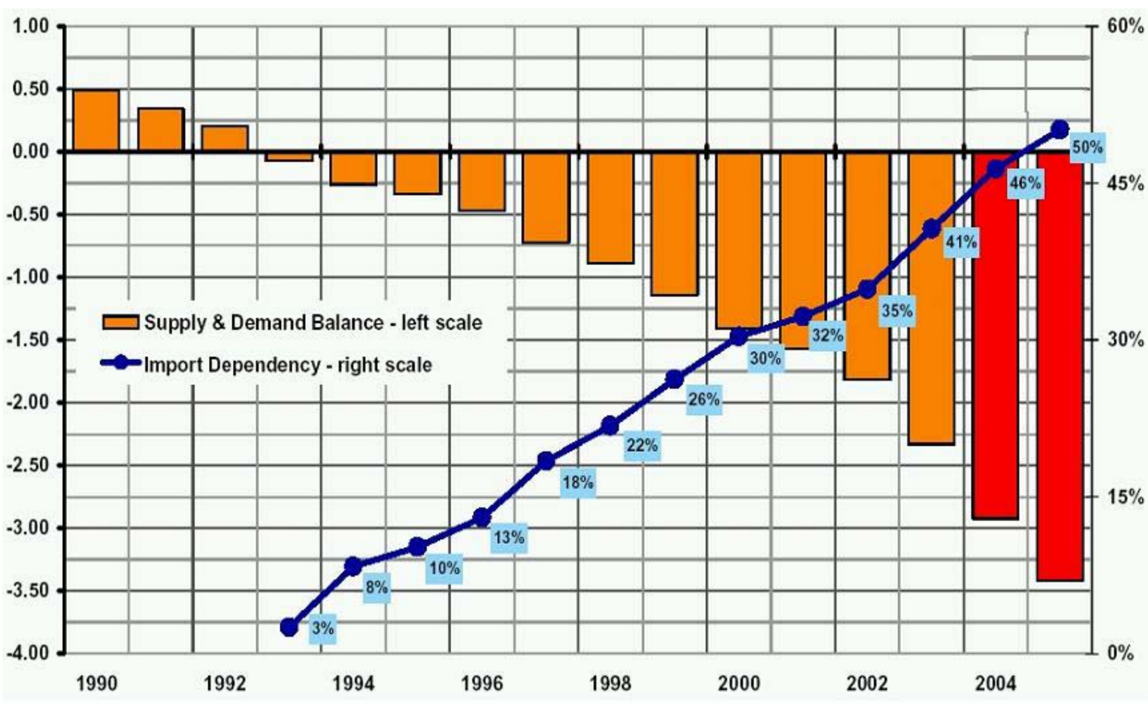

Figure 6. China's oil supply and demand: balance and import dependency (million b/d, %)[11].

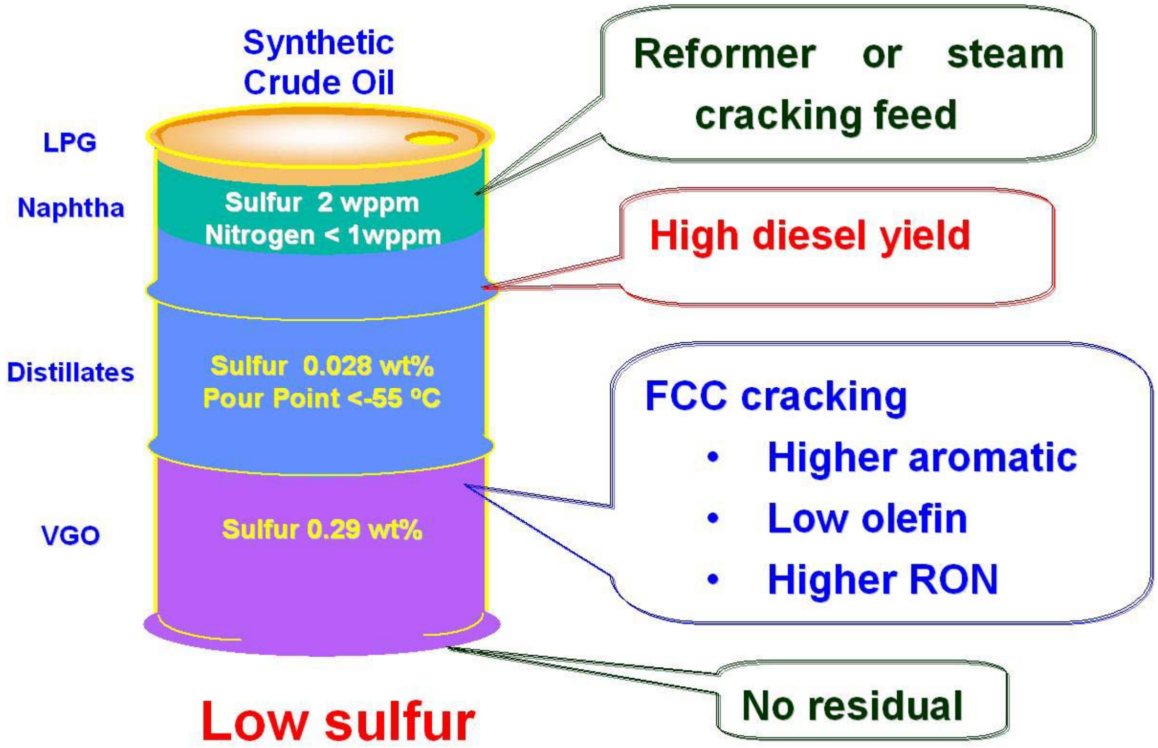

Figure 7. Desirable features of Alberta SCO for Chinese refineries [11].

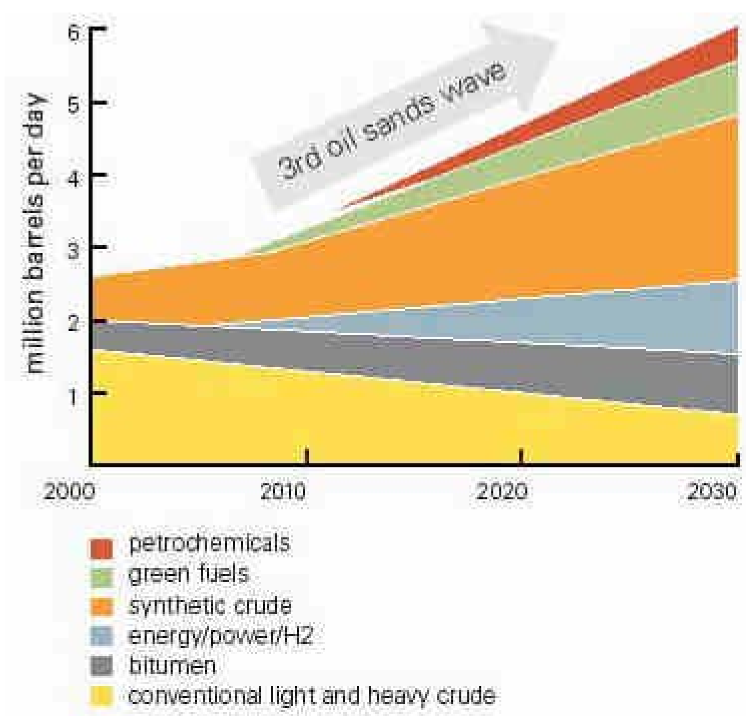

Figure 8. Future opportunitiees for value-added products from bitumen[2].